An Assessment of Economic Analysis Methods for Cogeneration Systems

J.N. Bolander Graduate Student
W.E. Murphy Assistant Professor
W.D. Turner Associate Professor
Department of Mechanical Engineering
Texas A&M University
College Station, TX 77843

ABSTRACT

Cogeneration feasibility studies were conducted for eleven state agencies of Texas. A net present value (NPV) analysis was used to evaluate candidate cogeneration systems and select the optimum system. CELCAP, an hour-by-hour cogeneration analysis computer program was used to determine the costs used in the NPV analysis. The results of the studies showed that the state could save over $6,000,000 per year in reduced utility bills. Different methods of analyzing the economic performance of a cogeneration system are presented for comparison. Other implications of the study are also discussed.

INTRODUCTION

The utility bills for the State of Texas exceeded $200,000,000 in FY '83. In a study conducted by the Energy Management Group of the Mechanical Engineering Department at Texas A&M for the Public Utility Commission of Texas (PUC), it was determined that cogeneration could possibly save the state millions of dollars per year in reduced utility bills. They suggested that a detailed feasibility study of cogeneration be conducted on several of the larger state agencies.

The PUC approved the study and awarded the contract to the Energy Management Group. Economic analyses of cogeneration were performed for eleven state agencies. Recommendations including the type and size of cogeneration system were made for each agency.

This paper outlines some available economic analyses and discusses in detail the economic analysis chosen for this study. It also describes the computer program used in the analysis and outlines the results of this study. Finally, some implications of the study are presented.

ECONOMIC ANALYSIS METHODS

Several methods are used by companies and governments to evaluate the economics of candidate projects. The three most popular methods are:

1. Simple payback
2. Net present value
3. Internal rate of return

The method of evaluation selected should be able to take into account the time value of money, rank the projects in order of economic attractiveness, and give the results in a meaningful unit of measurement.

Simple payback determines the time required for a project to recover its initial investment. It is calculated by dividing the project's initial investment by the expected profits (or savings) per unit time (usually in years):

$$PB = I/A$$

where:

PB = Simple payback (years)
I = Investment ($)
A = Profit or savings per unit time ($/year)

Simple payback does provide the results in a meaningful scale. It emphasizes the importance of time but not the time value of money. Also, it is not a recommended method of ranking projects, but it can still be used as a first order selection criterion.

The net present value (NPV) method determines the present value of the future costs and revenues of a project minus its initial investment:

$$NPV=\left[\sum_{n=0}^{N}(A_n - C_n)\times F_n\right] - I$$

where:

NPV = Net present value ($)
N = Number of time periods (project life in years)
A = Revenues for each time period n ($)
C = Expenses for each time peirod n ($)
F = Present value factor and is based on the discount (interest) rate for each period n (dimensionless)
I = Initial Investment ($)

The net present value method meets all of the criteria suggested in the opening paragraph of this section. It gives results in dollars, takes into account the time value of money using the present value factor, and can be used to reliably rank projects.

The internal rate of return (IRR) is defined as the interest rate paid on the time-varying unrecovered balances of an investment, such that the final investment balance is zero at the end of the proposed project. In other words, the IRR is determined by solving for the discount (interest) rate which makes the NPV equal to zero for a certain time period.

The IRR satisfies two of the criteria for economic evaluation, that is it takes into account the

Proceedings of the Second Symposium on Improving Building Systems in Hot and Humid Climates, College Station, TX, September 24-26, 1985

time value of money and it gives the results using a meaningful measure (interest rate and usually as a percent). Using this method, a project is deemed acceptable if its IRR is greater than a preset value which is usually called the minimum attractive rate of return or discount rate. However, the IRR is not a means of ranking the acceptable projects, i.e., the project with the highest IRR is not necessarily the best project. To select a project from the acceptable alternatives requires an incremental rate of return approach. The incremental rate of return is the IRR determined for the incremental cash flow that results from subtracting the cash flow of the less expensive project from the more expensive one. If the incremental rate of return is greater than the minimum attractive rate of return then the more expensive project should be selected. The following simple example will show each of the methods in use.

Consider two mutally exclusive projects, A and B. Project A requires an investment of one dollar and will have a net profit of one dollar per year. Project B requires an investment of two dollars and will have a net profit of one dollar and fifty cents per year. Both projects have four year lives, and the company's discount rate is five percent.

The results of each method of analysis are shown in the following table:

	PROJECT A	PROJECT B
Investment ($)	1	2
Annual Profit ($/yr)	1	1.5
Discount Rate (%)	5	5
Project Life (yrs)	4	4
Simple Payback (yrs)	1	1.33
Net Present Value ($)	2.55	3.32
Internal Rate of Return (%)	92.5	65.0

The simple payback and the internal rate of return suggest that project A is better while the net present value suggests project B. From inspection, the better project is B, providing the company has the two dollars to invest. The net present value method can be shown to be mathematically consistent.

As mentioned, when using the IRR method, an incremental internal rate of return is used to distinguish between two acceptable projects. To undertake project B instead of A it would cost one more dollar, and the annual profit would be increased by fifty cents over A for the four year life. The incremental internal rate of return would be 35% which is greater than the company's discount rate of five percent. Therefore, correct application of the IRR method also yields correct results.

One final note regarding economic analyses; the previous example neglects the existence of a project portfolio. The project portfolio is composed of those projects that as a whole maximize the profitability of the project budget which is usually fixed. For example, assume that in the previous example ten dollars are available for investment in projects and that there are ten more projects like A and five more projects like B. Obviously, project A is now more attractive than B, but the NPV and the IRR methods would also prove this, i.e., for a fixed budget, the portfolio which maximizes the IRR will also maximizes the NPV.

Since no fixed amount of money was specified for cogeneration opportunities at the eleven state agencies, and all moneys could be raised at the same discount rate, the NPV method was chosen for evaluating cogeneration candidates. In the presentation of results, however, simple payback was given due to its wide acceptance and use.

ECONOMIC ANALYSIS FOR STATE AGENCIES

For each state agency, the analysis that was used was based on annual costs and savings associated with each candidate cogeneration system. The following were identified as the primary economic factors:

1. Electricity cost before cogeneration (the base case) and after cogeneration
2. Fuel (natural gas in this study) costs before and after cogeneration
3. Power plant operating and maintenance (O&M) cost before and after cogeneration
4. Initial investment
5. Discount rate
6. Differential escalation rates for the cost of electricity and fuel
7. Standby power charges.

The next step was to develop an equation for calculating the NPV which incorporated the above variables.

$$
\begin{aligned}
NPV = {} & (EB-EA)x(1-(1+h)^{N}\,(1+i)^{-N})/(i-h) \\
& +(GB-GA)x(1-(1+f)^{N}\,(1+i)^{-N})/(i-h) \\
& +(OMB-OMA)x(1-(1+i)^{-N})/(i) \\
& -SPCx(1-(1+i)^{-N})/(i) - I
\end{aligned}
$$

where:

NPV = Net present value ($)
EB = Annual electricity cost before cogeneration ($)
EA = Annual electricity cost after cogeneration ($)
h = Differential escalation rate for the cost of electricity (escalation rate above inflation rate) (decimal)
i = Discount rate (decimal)
GB = Annual fuel cost before cogeneration ($)
GA = Annual fuel cost after cogeneration ($)
f = Differential escalation rate for the cost of gas (decimal)
N = Life of project (yrs)
OMB = Annual operating and maintenance cost after cogeneration ($)
SPC = Annual standby power charge
I = Initial investment

Since state agencies are not taxed entities a before tax analysis was requried. Differential escalation rates were considered only for gas and electricity; it was assumed that O&M cost and standby power charge costs would not escalate above the inflation rate. Also, the present value factors which contain the differential escalation rates are based on a geometric gradient series, i.e., each successive value is larger than the previous by h or f percent.

Conceptually, the approach used in the analysis can be described as follows. The first step was to establish the discount rate and the base case (the "do nothing" cas) annual costs: electricity, fuel (natural gas), and operating and maintenance (O&M). Secondly, the costs for the candidate cogeneration system including the initial investment were determined. Next, these numbers were substituted into the NPV equation and various differential escalation rate and standby power charge scenarios were then analyzed. The NPV for each scenario was then plotted as a function of installed electrical capacity of the cogeneration system. Finally, the best system overall was selected on the basis of optimum NPV.

So that the base case costs and the cogeneration case costs could be realistically compared, it was proposed to obtain both sets of numbers by computer simulation. CELCAP (Civil Engineering Laboratory Cogeneration Analysis Program), an hour-by-hour cogeneration computer simulation program was obtained for this purpose from the Naval Civil Engineering Research Lab in California. CELCAP takes hourly demands for electricity and steam for typical working and nonworking days for each month of the year and calculates monthly and annual costs for electricity, fuel, and O&M based on the utility rate structure, fuel prices, and O&M costs. CELCAP can be used to model the base case as well as the cogeneration case. For the cogeneration case, prime movers such as, gas turbines, diesel engines, back pressure steam turbines, and automatic steam turbines can be modelled singly or in any combination. The following is a list of input information required by CELCAP:

1. Hourly steam and electrical demand for typical working day and one nonworking day of each month for a year.
2. Boiler operating conditions, O&M cost, and boiler efficiency.
3. Type of prime movers to be used.
4. Performance characteristics of the prime movers.
5. Heat recovery steam generator operating conditions, O&M cost, and recovery efficiency
6. Utility rate structure (electricity).
7. Fuel price.
8. Price for electricity sold to utility grid.

Many of the agencies were able to supply hourly demands which were usually compiled by the agencies' energy management systems. For those not having hourly information available, demand profiles were constructed based on utility bills and hourly information from similar agencies.

To verify the demand profiles obtained from the agencies, CELCAP was run to model the base case. The monthly costs and consumptions of electricity and fuel were then compared with actual utility bills. The profiles were then altered for a particular month if the CELCAP generated information did not agree well with the billing information.

Using the same demand profiles, various sizes and types of cogeneration systems were analyzed. CELCAP offers three control mode options with each cogeneration system:

1. engines run at peak electrical output
2. engines follow electrical load (demand) up to their capacity
3. engines follow steam load (demand) up to their capacity

The annual costs of the best control mode were now used in the NPV equation. CELCAP does have the capability of a life cycle cost economic analysis, but the NPV analysis external to the main program proved to be more flexible and less time-consuming. The life cycle cost (LCC) analysis is a type of NPV analysis which determines the total cost of a project in today's dollars. The LCC's for the alternatives, including the "do nothing" case, are compared and the one with the lowest LCC is selected.

The next step in the NPV analysis was to determine the initial investment and the standby power charge. The initial investment figures (in 1984 dollars) used were based on vendor information and included all costs required to bring a system on-line: equipment, installation, engineering, and start-up. For gas turbine cogeneration systems, the costs were estimated to range from $500/KW for 20 MW systems to $1200/KW for 500 KW systems. Diesel engine cogeneration systems were estimated to range from $600/KW for 10 MW systems to $1100/KW for 200 KW systems.

The standby power charge is often neglected in many cogeneration economic analyses, but in most cases can significantly affect the profitability of cogeneration. Standby power is the capacity that the utility must have in the event the cogeneration facility experiences an unscheduled outage. Many current utility rate structures treat the charge for standby power for cogenerators the same as the demand charge. In other words, as long as the cogeneration system has no unscheduled outage, the cogenerator does not actually pay for the standby power. But, if the cogeneration system experiences an outage then a new peak demand will be established and the cogenerator will pay for all or most of that demand for the next twelve months due to the ratchet clause in the demand charge. The increase in demand for an outage would likely be equal to the capacity of the cogeneration system. In this analysis, this was assumed to be the case, therefore, the annual standby power charge was determined by multiplying the capacity of the cogeneration system by the monthly demand charge and then multiplying the product by twelve to take into account the ratchet clause for a year. Furthermore, it was assumed that the cogeneration facility would experience at least one unscheduled outage a year for the 20 year life of the system.

Some utilities, however, have different approaches to charging for standby power. A fixed monthly charge and ratchet clauses which use less than a twelve month period can be found. In many cases these standby charges are negotiable.

Due to the negotiability of the standby power charge two cases were usually analyzed: the worst case, the maximum standby power charge and the best case, no standby power charge. The worst case assumed that the cogeneration system would experience at least one unscheduled outage every year over the project's 20 year life, therefore, incurring the maximum standby power charge every year.

The final step in the NPV analysis was to determine the discount rate and the differential escalation rates. The discount rate used in the analysis was assumed to be the interest rate paid on the state of Texas long-term revenue bonds because this would probably be the method used to fund the projects. Discussions with financial analysts produced a discount rate of 8%.

A differential escalation rate, also called a real escalation rate, is the percentage increase in a cash flow above the general inflation rate over a period of time. In this analysis, it was assumed that the differential escalation rates for electricity and natural gas would vary from zero to 4%. The particular scenarios analyzed were where the differential escalation rates for the cost of electricity and natural gas were: (1) 0% and 0%, (2) 2% and 2%, (3) 4% and 2%, and (4) 2% and 4%, respectively.

Since the fuel charge in the electrical rate structure is primarily responsible for the escalation of electricity costs, it was assumed that the standby power charge would not escalate relative to the general inflation rate. It was also assumed that O&M costs would not escalate relative to the general inflation rate.

At this point all values in the NPV analysis have been explained. The NPV equation can now be solved.

COGENERATION FEASIBILITY STUDIES

Cogeneration feasibility studies, incorporating the described NPV analysis, were undertaken for eleven state agencies: two hospitals, eight universities, and the capitol complex in Austin. The completed studies were submitted to the Public Utility Commission (PUC) of Texas.

An important restraint in the analysis was the fact that state agencies, unless otherwise authorized, cannot sell electricity. Agencies authorized to sell power are utility authorities, e.g., the Lower Colorado River Authority (LCRA). As a result of this restriction, a cogeneration facility could not benefit from the sale of power, but the restriction also results in the economic feasibility of cogeneration being based on the demands of the agency only and not a function of the buyback rate.

A summary of the findings available at this writing is shown in Table 1. It can be seen that the potential savings from cogeneration at state agencies is significant.

Table 1 Economic Summary of Cogeneration

Institution	Cost ($ millions)	Electrical Capacity and type of prime mover (kW)	Annual Savings ($)	Annual Maximum Standby Power Charge (SPC) ($)	Simple Payback (yrs) with SPC	Simple Payback (yrs) no SPC	NPV ($ millions) (0,0) with SPC	(0,0) no SPC	(2,2) with SPC	(2,2) no SPC	(4,2) with SPC	(4,2) no SPC
1) Southwest Texas State University	3.6	4,500; GT**	800,000	0*	4.5	4.5	4.0	4.0	5.5	5.5	9.0	9.0
2) Austin State Hospital	1.1	1,000; GT	300,000	60,000	4.6	3.6	1.2	1.9	1.6	2.3	3.0	3.7
3) University of Houston University Park	6.6	8,800; GT	1,800,000	0*	3.7	3.7	10.0	10.0	13.0	13.0	22.0	22.0
4) Texas Woman's University	3.1	3,700; GT	1,050,000	250,000	3.9	3.0	4.8	7.2	6.5	8.9	9.2	11.6
5) North Texas State University & Texas Woman's University	6.6	8,800; GT	1,740,000	440,000	5.1	3.8	5.0	9.0	9.7	13.7	18.3	22.3
6) State Capitol Complex	2.0	2,500; DE***	360,000	110,000	5.5	8.0	0.6	1.6	1.4	2.4	4.0	5.0
7) University of Texas at Dallas	0.225	3,500; DE****	120,000	170,000	< 0	1.9	-1.25	0.75	-1.0	1.0	-0.1	1.9
Total	23.225	32,800	6,170,000	1,030,000	4.5	3.8	24.35	34.45	36.7	46.8	65.4	75.5

Net Present Value (NPV) ($ millions): Electricity and Gas Cost Escalation Rates, (%,%)

Notes:

* The standby power charge was assumed to be negligible.

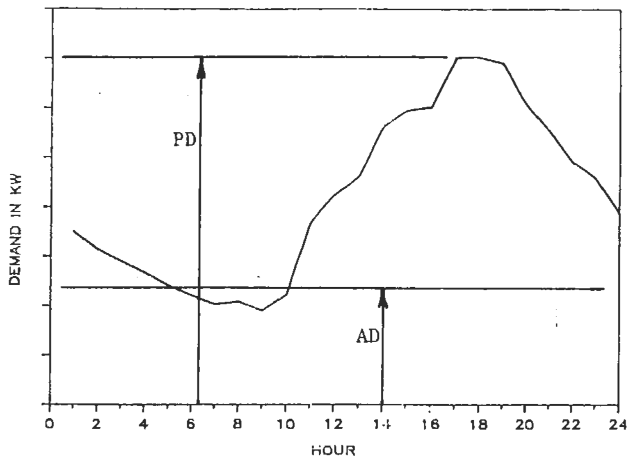
** GT - Gas Turbine.

*** DE- Diesel Engine (natural gas-fired)

**** Cogeneration System already in place - cost shown is for interconnection switchgear.

IMPLICATIONS OF THE ANALYSIS

An important implication that results from the installation of a base-load cogeneration system is the fact that the cost of electricity purchased on a kilowatt hour basis from the utility would go up. In other words, the price of electricity displaced by the cogeneration system is actually lower than the average price of electricity bought before cogeneration. To illustrate, consider the following typical electrical demand profile:



The price of electricity for this day would be calculated as follows:

ELEC = (KWH x E + KWH x FA + PD x DC)/KWH

where:

ELEC = average cost of electricity ($/kWh)
KWH = electrical energy consumed (kWh)
E = energy charge ($/kWh)
FA = fuel adjustment charge ($/kWh)
PD = peak demand (kW)
DC = demand charge ($/kW)

simplication gives:

ELEC = E + FA + (PD x DC)/KWH

Now define:

AD = KWH/HR

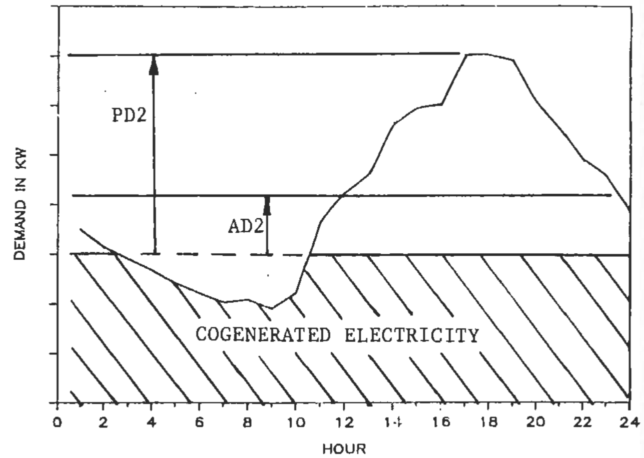
where:

AD = the average demand for the period (kW)
HR = time in period (hrs)

substituting:

ELEC = E + FA + (PD x DC)/(AD x HR)

Therefore, it can be seen that the electricity cost is a function of the ratio of PD to AD for any given rate structure. Now assume that a base-load system is installed at the site and carries the load as indicated:



It can be seen from comparing PD2 and AD2 with PD and AD that the ratio of peak demand to average demand goes up as more of the base electricity demand is carried by the cogeneration system, and hence, the price of electricity goes up. An hour-by-hour analysis, like that used in CELCAP, can take into account the changing average price of electricity and in part prevent the savings from being overstated.

From the study it also became clear that the standby power charge was extremely important. As shown in the table of results, the standby power charge for a single unscheduled outage can greatly reduce or erase any savings from cogeneration for a full year.

Although the NPV is sensitive to the differential escalation rates for fuel and electricity, the optimum cogeneration system is not a strong function of differential escalation rates. In other words, the optimum cogeneration system is virtually independent of the differential escalation rates, but the actual dollar value of the system is a strong function of the differential escalation rates.

SUMMARY

Cogeneration feasibility studies have been completed for seven of the eleven selected state agencies. The results indicate that Texas could install a total of 33MW of cogenerated electrical capacity for $23.3-million and subsequently save over $5-million per year in reduced utility bills.

A net present value (NPV) analysis was used as the primary selection criterion. It was chosen because it can reliably rank alternatives, take into account the time value of money, and give results in a meaningful unit of measure. Also, it can easily be used to analyze an alternative's sensitivity to differential escalation rates and standby power charges.

An hour-by-hour cogeneration analysis program called CELCAP was used for calculating the annual costs used in the NPV analysis. The importance of an hour-by-hour analysis was shown by the fact that it can take into account the increasing average price of electricity due to the demand charge and installation and operation of a cogeneration facility.

REFERENCES

1. Fleischer, G.A., Engineering Economy, Wadsworth, Inc., Belmont, California, 1984.
2. Civil Engineering Laboratory Cogeneration Analysis Program User Documentation, Naval Civil Engineering Laboratory, Report no. CR 81.001, March 1981.